BEFORE THE
PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA

DOCKET NO. 2020-264-E
DOCKET NO. 2020-265-E

In the Matter of:	)	
	)	
Duke Energy Carolinas, LLC's Establishment of Solar Choice Metering Tariffs Pursuant to S.C. Code Ann. Section 58-40-20	)	**REBUTTAL TESTIMONY OF JANICE HAGER FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**
	)	
Duke Energy Progress, LLC's Establishment of Solar Choice Metering Tariffs Pursuant to S.C. Code Ann. Section 58-40-20	)	

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Janice Hager and my business address is 2049 Mount Zion Church Road, Alexis, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am President of Janice Hager Consulting, LLC.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have extensive experience with Duke Energy Corporation over a 34-year career with the company. I am a civil engineer, having received a Bachelor of Science in Engineering from the University of North Carolina at Charlotte. During my time at Duke Energy Corporation I was a registered professional engineer in North Carolina and South Carolina. I worked in Duke Power's (now Duke Energy Carolinas, LLC) Rates and Regulatory Affairs area for ten years, the last three of which I was Vice President of the department. Following the merger of Duke Energy and Progress Energy, Inc., I led Duke Energy's integrated resource planning process for all of the Company's regulated utilities, including Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC", and collectively with DEP, "the Companies"). At the time of my retirement in December 2014, I was Vice President of Integrated Resource Planning and Analytics for Duke Energy. Upon my retirement, I established Janice Hager Consulting LLC whereby I provide energy consulting services for Duke Energy Corporation as well as other clients.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA?

A. Yes. I have filed testimony and appeared before the Public Service Commission of South Carolina ("Commission") many times including on matters of Cost of Service, Fuel Adjustment Clauses, Integrated Resource Planning, Certificates of Public Convenience and Necessity and other issues. I have also appeared before the North Carolina Utilities Commission, the Indiana Utilities Regulatory Commission, and the Federal Energy Regulatory Commission ("FERC"). I last testified before this Commission when I served as the Cost of Service witness in the most recent DEP and DEC rate cases (Docket Nos. 2018-318-E and 2018-319-E, respectively).

Q. ARE YOU INCLUDING ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I have attached my resume as **Hager Rebuttal Exhibit 1** to provide additional information regarding my background and experience.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to address the issues raised by the South Carolina Office of Regulatory Staff's ("ORS") Witness, Brian Horii, regarding the Companies' use of the embedded cost of service ("COS") study and specifically the use of the Summer coincident peak allocator (the "Summer CP"). Witness Horii advocates a switch to a winter peaking methodology or Loss of Load Expectation ("LOLE") methodology without prior Commission approval. I explain that all

South Carolina retail rates for the Companies are based on the COS methodology arising from the Companies' last base rate cases—which is based upon the Summer CP—and that no other methodology has been fully vetted and approved by this Commission.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony demonstrates why the Commission should not rely upon Witness Horii's analyses. Witness Horii does not support use of the embedded COS study methodology that underlies the rates currently in place that were approved by the Commission in the most recent rate cases for the Companies as the basis for measuring the cost shift and subsidization associated with tariffs proposed by the Companies in this proceeding (the "Solar Choice Tariffs"). He believes the method used by the Companies under the proposed Solar Choice Tariffs understates the amount of cost shift that remains in effect. However, Witness Horii uses different COS methodologies to determine the cost shifts and subsidization which produce an incorrect result, as explained by Witness Huber.

I show that use of any COS study methodology other than the method underlying the most recently approved rates by this Commission is inappropriate because 1) all South Carolina retail rates for the Companies are based on this COS methodology and the current rates have no generation asset costs based on winter peaking needs, and 2) no other methodology has been fully vetted and approved by this Commission in a proceeding in which all interested parties have a voice, such as a base rate proceeding, which is the normal forum to consider COS methodology. Witness Horii's suggested use of LOLE based on its use in avoided cost to determine the cost shift for the embedded cost shift arising from Net Energy Metering ("NEM") is not sound given that that COS studies functionalize, classify, and allocate historical embedded costs based on cost causation, and the avoided cost process is based on incremental (or marginal) costs. Put simply, Witness Horii's allegation that these NEM rates should be developed using anything other than the Summer CP is incorrect and in contradiction to the Commission's approved COS methodologies.

II. COS STUDY OVERVIEW

Q. WHAT IS THE PURPOSE OF A COS STUDY?

A. The purpose of a COS study is to align the total costs incurred by the utility in the test period with the jurisdictions (i.e. South Carolina and North Carolina) and customer classes (i.e. Residential, Commercial, etc.) responsible for the costs. The study directly assigns or allocates the Companies' revenues, expenses, and rate base among the regulatory jurisdictions and customer classes served by the Companies based upon the service requirements of those respective jurisdictions and customer classes. These service requirements are based on a number of factors, including differences in usage patterns and size.

Cost causation is the key component in determining the appropriate assignment of revenues, expenses and rate base among jurisdictions and customer classes. The National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual states that one of the purposes of COS studies is "to attribute costs to different categories of customers based on how those customers cause costs to be incurred."[1] Under the principle of cost causation, costs are assigned to the specific jurisdictions and customer classes that "caused" such costs to be incurred. Once all costs and revenues are assigned, the study identifies the return on investment the Companies have earned for each customer class during the test period. These returns can then be used as a guide in designing rates to provide the Companies an opportunity to recover their costs and earn their allowed rate of return.

Q. SHOULD THE COS STUDY FULLY ALLOCATE COSTS AMONG JURISDICTIONS AND CUSTOMER CLASSES?

A. Yes. Because the COS study is used as a guide in designing rates, all costs must be allocated to the appropriate jurisdiction and customer class. If any costs are omitted or remain unallocated, then the utility's rates will not allow for full recovery of the utility's operating expenses, including a return of and on its capital expenditures.

Q. PLEASE EXPLAIN HOW COSTS ARE ASSIGNED TO THE DIFFERENT JURISDICTIONS AND CUSTOMER CLASSES IN COS STUDIES.

A. Generally, there are three key activities that occur when assigning costs in a COS study:

A. **Functionalization -** Costs are grouped according to their "function." Functions include production (generation), transmission, distribution, and customer service, billing and sales.

B. **Classification -** Functionalized costs are then grouped or classified based on the utility "operation" or service being provided and the related causation

[1] *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, January 1992, p 12.

of the costs. Typical classifications include demand, energy, and customer-related costs.

C. **Allocation -** Finally, the costs, which have been functionalized and classified, are allocated or directly assigned to the proper jurisdiction and customer class based on the manner in which the costs are incurred (*i.e.,* based on cost causation principles).

A. Functionalizing Costs

Q. PLEASE EXPLAIN HOW COSTS ARE FUNCTIONALIZED.

A. The Companies account for costs using the Uniform System of Accounts ("USOA") of the FERC. The USOA assigns the costs of the Companies' plant investment into the primary categories of production (generation), transmission, distribution, and general and intangible plant. Similarly, the USOA categorizes the Companies' operating costs into production, transmission, distribution, customer services, and administrative and general functions.

B. Classifying Costs

Q. PLEASE EXPLAIN HOW COSTS ARE CLASSIFIED.

A. Functionalized costs are classified according to their cost-causation characteristics. These characteristics are typically defined as demand-related, energy-related, or customer-related.

Q. PLEASE DEFINE DEMAND-RELATED COSTS.

A. Demand-related costs are costs incurred that vary in direct relationship to the kilowatts ("kW") of demand that customers place on the various segments of the system. "Demand" means the average amount of kilowatts of electricity that a customer or a customer class uses over the course of a given hour. For example, a residential customers demand might vary from a low of less than 1 kW on a mild fall or spring day to a maximum of 8 kW on the hottest day or coldest morning. Costs that are classified as demand-related include major portions of the utilities' investment and related expenses in its production and transmission facilities and a significant portion of the investment and related expenses of its distribution system. These costs tend to remain constant over the short run and do not change based on the amount of energy consumed. These costs are often referred to as fixed costs.

Q. PLEASE DEFINE ENERGY-RELATED COSTS.

A. Energy-related costs are costs incurred that vary in direct relationship to the amount of energy or kilowatt hours ("kWh") generated and delivered. These costs are often referred to as variable costs. Fuel is the largest of these variable costs.

Q. PLEASE DEFINE CUSTOMER-RELATED COSTS.

A. Customer-related costs are costs incurred as a result of the number of customers being served. Customer costs do not vary with the customer's volume of usage but are instead related to the number of customers.

C. Allocation and Direct Assignment of Costs

Q. PLEASE EXPLAIN HOW COSTS ARE ALLOCATED AND DIRECTLY ASSIGNED.

A. Cost components identified as having a direct relationship to a jurisdiction or customer class are directly assigned to that jurisdiction or class before any allocations occur. For example, many distribution-related costs are directly assigned to a jurisdiction based on their state location. For those costs, as well as the remaining unassigned costs, specific allocation factors are developed that relate to the (1) demand, (2) energy, and (3) customer-related classifications identified above.

1. Demand Allocators

a. Production and Transmission Demand – Utilities use various methods of allocation for Production and Transmission Demands costs, including single coincident peak, multi-month peaks, and a combination of peaks and energy. The allocation of Production Plant is often a focus in rate proceedings. I discuss below the method the Companies used in the most recent cases.

b. Distribution Demand - Distribution plant investments are directly assigned to the jurisdictions. At the customer class level, substations, and a part of poles, lines and transformers that have been designated as demand-related are allocated based on the Non-Coincident Peak Demand.

2. Energy Allocators

Q. WHAT ALLOCATORS ARE USED TO ASSIGN ENERGY-RELATED COSTS TO JURISDICTIONS AND CUSTOMER CLASSES?

A. Energy-related costs reflect the variable cost of producing, transmitting, and delivering electricity. Examples of costs allocated on this basis are fuel costs and variable production costs incurred at generating stations. A utility's kWhs of generation and deliveries during the test period are used to allocate these variable costs.

3. Customer Allocators

Q. WHAT TYPES OF COSTS ARE INCLUDED FOR ALLOCATION AS CUSTOMER-RELATED?

A. Operating expenses such as the costs of the service drop to the premises and the meter, meter reading, billing and collection, and customer information and services are considered customer-related costs. In addition, the Companies include in this category a portion of distribution costs that the Companies have identified as customer-related.

Q. WHAT IS THE RELATIONSHIP BETWEEN COS AND RATE DESIGN?

A. The COS study breaks down the revenue requirement by rate class to its constituent components such as demand-related production costs and energy-related production costs. The COS study is then provided to those doing rate design as the starting point for establishing cost-based rates. Setting rates that are aligned with unit cost minimizes cross-subsidization within a rate.

Using a pie analogy, the revenue requirement the Companies are seeking to recover through rates is the size of the whole pie. The revenue requirement is based on historical embedded costs. COS studies divide the pie into rate classes, based on how each class caused costs to be incurred. Rate design provides the utensils for each piece of the pie to be consumed. Rate design can, and typically does, use marginal costs to set the prices of specific charges, which helps ensure the utility is sending the appropriate price signal. However, the total estimated revenue for the rate schedules must equal the embedded costs (i.e. the revenue requirement). In summary, COS studies functionalize, classify, and allocate <u>historical</u> costs based on cost causation, whereas rate design can utilize forward looking methodologies to send appropriate price signals.

III. REVIEW OF THE COS STUDY METHODOLOGY UNDERLYING THE CURRENT RATES

Q. WHAT DEMAND ALLOCATORS WERE USED TO ASSIGN PRODUCTION AND TRANSMISSION DEMAND COSTS TO JURISDICTIONS AND CUSTOMER CLASSES IN THE MOST RECENT RATE CASES?

A. Production & Transmission demand costs were allocated using the Summer CP.

Q. PLEASE EXPLAIN THE CONCEPT OF ALLOCATING COSTS BASED ON COINCIDENT PEAK.

A. A coincident peak ("CP") allocator assigns the fixed, demand-related costs (for example, a portion of production and all transmission-related costs) to the jurisdictions and customer classes in proportion to their respective contribution to the entire system's peak hourly demand during the test period. Each jurisdiction and customer class' cost responsibility (*i.e.*, the percentage of the fixed portion of production and transmission demand costs assigned to each jurisdiction and customer class) is equal to the ratio of their respective demand in relation to the total demand placed on the system. The COS study supporting the Companies' rate design in the most recent rate cases allocated the fixed portion of production and transmission demand-related costs based upon each jurisdiction's and customer class' coincident peak responsibility occurring during the summer, otherwise known as the Summer CP.

IV. WITNESS HORII'S CONCERNS

Q. WHAT IS WITNESS HORII'S CONCERN WITH THE APPROVED COS METHODOLOGY?

A. Witness Horii claims on page 7, lines 12-15, of his direct testimony that the "continued use of the [Summer CP] in the COS studies creates outdated and unreliable results for determining the cost shift embedded in the Permanent Tariffs." As I explained above, the Companies have used this methodology for many years. No party, including the ORS, challenged that methodology in the most recent rate cases. In fact, ORS Witness Michael Seaman-Huynh testified that, "ORS concluded that, for the purposes of this Application, the methodology applied in constructing the Company's COSS is reasonable."[2] The Commission was silent on the issue in the DEP Order, but stated explicitly in the DEC Order that:

> The Commission finds and concludes that for purposes of this proceeding, the Company may continue to use the [Summer CP] methodology for allocation between jurisdictions and among customer classes and that the Company's cost of service methodology is just and reasonable. The methodology provides a reasonable assessment and allocation of the Company's revenues, operating expenses and rate base items."[3]

The Companies prepared a compliance COS study for DEC and DEP to conform to the Commission's orders in the rate cases and these COS studies were used to develop the compliance rates filed with the Commission, which are the same base rates that are currently in place for the Companies.

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[2] Direct Testimony of Michael Seaman-Huyhn, p. 6, lines 3-6, in Docket No. 2018-318-E and p.5, lines 13-16 in Docket No. 2018-319-E.

[3] Order No. 2019-323 dated May 21, 2019, in Docket No. 2018-319-E, p. 32.

As noted above, COS studies allocate historical embedded costs. These allocations establish the historical cost to serve each rate class. Each customer class's historical cost allocation is then converted to a unit cost. It is this unit cost that is being used in the development of the Solar Choice Tariffs. Measuring under- or over-recovery of the proposed Solar Choice Tariffs against unit costs from the COS studies that provide the basis for the current rates is the only appropriate methodology. Changing the unit cost as suggested by Witness Horii completely disconnects the analysis from the Commission-approved rates.

Q. WITNESS HORII STATES ON PAGE 6 OF HIS DIRECT TESTIMONY THAT THE PROPOSED RATES IN THE SOLAR CHOICE TARIFFS ARE BASED ON "FLAWED EMBEDDED COS STUDY ANALYSES." DO YOU AGREE THAT THE COS STUDIES USED AS THE BASIS FOR THE TARIFFS IS FLAWED?

A. No. The "flaw" he notes is that the analyses are based on COS studies from the most recent rate cases.[4] The Embedded COS Studies that are the starting point of the Embedded Cost Shift studies discussed by the Companies' Witness Harris were developed in mid-2019 as result of the May 2019 Orders in the 2018 base rate cases for DEC and DEP.[5] This is not a "flaw;" this is the normal course of ratemaking. Given the length of time associated with the normal ratemaking process, it is always true that the rates customers pay are based on analyses that were performed in the past.

[4] Horii direct, p. 7, lines 4-7.

[5] Order No. 2019-323, issued in Docket No. 2018-319-E, dated May 21, 2019, and Order No. 2019-341, issued in Docket No. 2018-318-E, dated May 21, 2019.

It is these studies that served as the basis for the rates currently in place for the Companies' retail customers in South Carolina. Reliance on the Embedded COS Studies underlying the current rates is not a "flaw." No other embedded COS study would be appropriate for the design of the Solar Choice Tariffs. I consider the results postulated by Witness Horii as flawed given that they are based on methodologies that this Commission has not approved for retail base rates for the Companies.

Q. WHAT METHODS DOES WITNESS HORII USE INSTEAD OF THE MOST RECENT COMMISSION-APPROVED COS?

A. Witness Horii measures cost shifts and subsidization using a winter peak and LOLE. His rationale for winter peak is that the "Duke system now peaks primarily in the winter morning."[6] His rationale for using LOLE is that this is now the accepted method for the Companies' avoided cost proceedings.[7] I address each of the methodologies below.

Q. WITNESS HORII CONTENDS ON PAGES 7 AND 8 OF HIS TESTIMONY THAT "THERE IS NO VALID REASON, OTHER THAN CONSISTENCY WITH PAST PRACTICE, FOR KEEPING TO A [SUMMER CP] METHOD WHEN SUPERIOR PROBABLISTIC METHODS ARE ALREADY BEING USED FOR RESOURCE ADEQUACY PLANNING AT DUKE." WAS THE SUMMER CP ONLY APPLIED FOR CONSISTENCY PURPOSES?

A. No. There are a number of reasons for continuing to use the COS study based on Summer CP.

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[6] Horii, p. 7, lines 9-10.
[7] Horii, p. 36, lines 12-16.

1. Connection to the current Commission approved retail rates: All retail rates in the Companies' jurisdictions in North and South Carolina are based on the Summer CP cost allocation methodology for demand-related production and transmission costs. In fact, the current rates have no generation asset costs based solely on winter peaking needs. If an alternative allocation methodology was used only for Solar Choice Tariffs, it would violate the basic logic of cost allocation. All of the allocators used for each customer class should sum to 100%. Returning to the pie analogy, changing one customer class's allocator changes the size of only that one slice of pie. If two different cost allocation methodologies are utilized, then the allocators will no longer sum to 100% and therefore the Companies will either be over- or under-collecting the Commission-approved revenue requirement.
2. There is a sound basis for the use of Summer CP for retail COS: The rationale for use of Summer CP is grounded in the "cost causation" principles of COS. The demand-related production costs allocated using the Summer CP method were put into service based on the summer peak and therefore each class' summer peak "caused" those assets to be built and placed into service. Applying a different allocator would assign costs to customers who did not cause those costs to be incurred.
3. The need for a formal vetting of any proposed change to the COS methodology due to the potential for large cost shifts: Any change in the cost allocation method for demand-related production costs will need to be carefully considered and fully vetted by the Companies, interested parties, and this Commission. In particular, moving from summer to winter peak allocation for the allocation of demand-related

production costs in a future rate case would likely be strongly debated because of the large cost shifts between rate classes which can lead to concerns about rate shock. This proceeding is not an appropriate venue for modifying allocators, even for one subset of customers; this should only be modified in a base rate proceeding where all interested parties are participants—particularly given that any such change would likely be of interest to numerous parties who are not part of this docket. For example, in the most recent South Carolina base rate cases for the Companies,[8] there were 13 intervenors, 5 public hearings with hundreds of customers present, and 10 days of evidentiary hearings for the two cases combined—a stark contrast to the procedural posture of this docket. The Commission must consider many points of view in reaching its decisions regarding the Companies' rates. It is not appropriate to change one isolated element outside a base rate case.

Q. HAVEN'T THE COMPANIES SHIFTED TO WINTER PEAK FOR INTEGRATED RESOURCE PLANNING PURPOSES? PLEASE ADDRESS.

A. Prior to 2016, the Companies conducted their integrated resource planning by focusing on the summer peak demand and the resources needed to meet that load plus an adequate planning reserve margin. Focusing on a summer peak also ensured adequate resources for a winter peak because natural gas-fired resources historically had significantly greater potential MW output in the winter due to the colder, drier intake air. Therefore, even if the summer and winter peaks were close,

[8] PSC SC Docket Nos. 2018-318-E and 2018-319-E.

planning focused on the need to meet the summer reserve margin. However, beginning in 2016, DEP began focusing more on the winter-peak generation resource planning. A key driver for this change is the fact that the load and resource balance has changed drastically in the past few years, driven primarily by the high penetration of solar resources as well as the significant load requirements in response to recent cold weather. Therefore in 2016, the Companies' integrated resource planning transitioned to winter capacity planning. By focusing on the winter peak load and the required winter reserve margin, the Companies can assure that summer peak loads are met as well. While winter peak planning will likely continue, both summer and winter peaks are important in the planning process.

As I noted earlier, continued use of the Summer CP methodology in the most recent rate case was grounded in the fact that the costs the Companies were seeking to recover were invested on the basis of summer peak planning. The current rates have no generation asset costs based on winter peaking needs. In future cases, as more assets are added based on the new integrated resource plans and are being proposed for inclusion in rates, the Companies will consider other methodologies for cost allocation.

Q. WITNESS HORII NOTES ON PAGE 8, LINES 10-14, OF HIS TESTIMONY THAT THE COMPANIES' EMBEDDED COS STUDIES ASSUME THE DEC AND DEP SYSTEM PEAKS REMAIN IN THE SUMMER. IS THIS AN ACCURATE STATEMENT?

A. No, Witness Horii is incorrect. The embedded COS studies make no assumption about the future of system peaks. Instead, they rely appropriately on historical information and cost causation principles which led to an allocation of demand-related production costs based on Summer CP.

At a minimum, Witness Horii's concerns are premature. If the COS studies in future rate cases result in a change in the Commission approved allocation of demand-related production costs, the cost shift and subsidization calculations will be updated and reflected in the Solar Choice Tariffs as appropriate and with considerations of gradualism.

Q. PLEASE ADDRESS THE USE OF COS BASED ON LOLE FOR MEASURING COST SHIFTS.

A. Witness Horii also measures cost shifts and subsidization using the Companies' LOLE analyses.[9] His support for the LOLE appears to be the use of LOLE for the Companies' avoided cost proceedings.[10] Calculation of avoided costs are a very different concept than methodologies seeking to recover historical embedded costs. Avoided costs proceedings are for the purpose of setting future purchased power rates in accordance with Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Pursuant to Sections 201 and 210 of PURPA, electric utilities such as DEC and DEP are required to offer to purchase electric energy from qualifying cogeneration and small power production facilities ("QFs"). This is known as the "mandatory purchase obligation" under PURPA. Pursuant to S.C. Code Ann. § 58-27-865, the customers of electric utilities are responsible for paying for all power purchased from QFs.[11] PURPA requires that the rates electric utilities

[9] Horii, p. 36, line 12. It is odd that Witness Horii asserts on page 7, lines 4-5 that the 2018 COS studies are "outdated", but then attempts to correct this by using even older 2016 Resource Adequacy Studies.
[10] Horii, p. 36, lines 12-16
[11] *See* 16 U.S.C. § 824a-3(a).

pay to purchase QF energy shall not exceed the electric utilities' "avoided costs," which PURPA defines as the **incremental cost** to the electric utility of the electric energy, which, but for the purchase from such QFs, such utility would generate or purchase from another source.[12] Use of LOLE is appropriate for avoided cost proceedings which focus on marginal costs but not for allocation of embedded historical costs.

Q. IS THE USE OF AN EMBEDDED COS ALLOCATION FOR DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS BASED ON LOLE A STANDARD PRACTICE FOR UTILITIES?

A. No. I was able to find only two utilities in the country—Kentucky Utilities and Louisville Gas and Electric—who used Loss of Load Probability ("LOLP") (another way of expressing LOLE) for COS for allocation of demand-related production costs for general rate cases. The Kentucky Public Service Commission's acceptance of this method was lukewarm at best and these two companies were ordered to provide another alternative along with the LOLP in their next rate cases.[13]

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[12] 16 U.S.C. § 824a-3(b), (d).

[13] April 30, 2019 Order in the Matter of Electronic Application of Kentucky Utilities for an Adjustment of its Electric Rates, Case No. 2018-00294. The Order at pages 18 and 19 says, "The Commission does not explicitly reject the LOLP methodology, but recognizes that the LOLP methodology has not been adopted in other jurisdictions, that the probabilities are estimates based upon a proprietary software package, and … that the LOLP methodology is still rather new. Therefore, the Commission finds that in KU's next base rate case than an alternative COSS should be filed along with the LOLP COSS." (Footnotes omitted.) April 30, 2019 Order in the Matter of Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates, Case No. 2018-00295. The Louisville Gas and Electric order has the same language at pages 20-21 of the Order.

Q. WITNESS HORII ARGUES ON PAGE 18 OF HIS DIRECT TESTIMONY THAT NO NEW EMBEDDED COS STUDIES WOULD BE NEEDED TO EVALUATE THE FULL IMPACT OF A WINTER PEAK. DO YOU AGREE?

A. No. Changing to a 1 Winter CP methodology would require a new embedded COS study for all retail customers. To change only one "piece of the pie" is disingenuous. As discussed previously, a utility cannot use one allocation methodology for one rate class and a different methodology for another. This would result in an over- or under-collection of the revenue requirement. Also, as noted above, it is very uncertain as to what methodology for allocating embedded production and transmission costs may be proposed by the Companies in the future. At the time such a change is proposed, there is likely to be much discussion as to the proposal by many parties who are not part of this docket, and the Commission's ultimate decision is also unknown. Using unapproved, non-vetted COS studies in designing the Solar Choice Tariffs is not sound.

V. CONCLUSION

Q. DO THE COMPANIES' COS STUDIES USED FOR THE MOST RECENT RATE CASES PROPERLY ESTABLISH UNIT COSTS FOR USE IN THE DESIGN OF THE SOLAR CHOICE TARIFFS?

A. Yes, they do. The COS studies based on the most recent rate cases provide the proper foundation for distributing costs among the jurisdictions and customer classes because it recognizes cost causation and distributes costs accordingly, and moreover it reflects what was used to set rates that are still in place today.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

Janice Hager

►M: 704.451.0861 ► janice@janicehagerconsulting.com

Executive with 35+ years in the utilities industry and deep experience in integrated resource planning, generation analytics, rates, and regulatory affairs in challenging and continually evolving economic, environmental and operating circumstances. Testified numerous times before state utility commissions. Strengths include a results-oriented and analytical mindset, the ability to understand and communicate both the big picture and the details of highly technical information to all types of audiences; see both sides of an issue; make sound decisions; and problem-solve.

Work History

Janice Hager Consulting, LLC, Alexis, NC **2015 - Present**

Comprehensive consulting services in the areas of integrated resource planning, generation analytics, rates, and regulatory affairs from an experienced utility executive with extensive experience testifying in regulatory proceedings.

Consultant, Duke Energy Corporation, 2/2016 – present

Expert cost of service witness in six rate cases. Consultant on innovative planning project.

1981 – 2014

Duke Energy Corporation, Charlotte, NC

REGULATORY AFFAIRS

- Testified numerous times before the Indiana, North Carolina, and South Carolina utilities commissions to support Company plans to build more than $17 billion in new generation assets.
- Key participant in many settlement processes with intervenors in regulatory proceedings (see Appendix).

STRATEGIC PLANNING

Was responsible for:

- The preparation and defense of long-term plans for six utilities to ensure the provision of reliable, environmentally-sound, and reasonably priced electricity.
- Analysis to support environmental compliance v. retirement decisions for electric generation stations.
- Developing Vision 2030 --a plan to determine what it would take for Duke Energy to reduce its carbon footprint significantly by 2030.

VP, Integrated Resource Planning and Analytics, Charlotte, NC, 7/1/2012 - 8/15/2014 *(post-merger with Progress Energy)*

VP, Integrated Resource Planning and Regulated Analytics, 10/1/2009 – 6/30/2012 *(post-merger with Cinergy)*

Managing Director, Integrated Resource Planning, 11/1/2006 – 9/30/2009 *(post-merger with Cinergy)*

VP, Rates and Regulatory Affairs, Duke Power 4/1/2003 – 11/1/2006

Duke Energy Corporation, Charlotte, NC
Manager, Rate Design and Analysis, Duke Power, 11/1/1998 – 3/31/2003

Education

- Gardner-Webb University, Boiling Springs, NC, Masters of Divinity, December 2014
- Gaston College, Gastonia, NC, Accounting courses, 2012-2018
- University of North Carolina Charlotte, BS, Engineering, 1981

Board Experience

Christian Service Organization for Gardner Web University, secretary/treasurer

Immigration Hospitality Center, board member since 2020

Other

Formerly Licensed Professional Engineer in North Carolina: 9/18/1985, Professional Engineer in South Carolina, 5/5/1987, until 12/31/2015.

Appendix

Testified in the following regulatory proceedings:

NORTH CAROLINA UTILITIES COMMISSION

Docket No. E-7, Sub 746 – Approval of 2004 Duke Power Fuel Charge Adjustment - $938 million fuel expense

Docket No. E-7, Sub 780 – Approval of 2005 Duke Power Fuel Charge Adjustment - $1,113 million fuel expense

Docket No. E-7, Sub 790 – Approval to Construct the 800 MW Cliffside Coal Project - $1.8 billion facility

Docket No. E-7, Sub 795 – Approval of Merger between Duke Energy and Cinergy Corporation

Docket No. E-7, Sub 805 – Approval of 2006 Duke Energy Carolinas Fuel Charge Adjustment - $1,318 million fuel expense

Docket No. E-7, Sub 819 – Approval to Incur Project Development Costs for Lee Nuclear Station - $11 billion project

Docket No. E-7, Sub 831 – Approval for New Energy Efficiency Programs and Cost-Recovery

Docket No. E-7, Sub 791– Approval to Construct the 620 MW Buck Combined Cycle Facility - $700 million project

Docket No. E-7, Sub 832 – Approval to Construct the 620 MW Dan River Combined Cycle Facility- $700 million project

Docket No. E-7, Sub 856 – Approval for Photovoltaic Distributed Generation Program (Order dated 12/31/2008)

Docket No. E-7, Sub 858 – Approval of Wholesale Power Sale to the City of Orangeburg, South Carolina (Order dated 3/30/2009)

Docket No. E-7, Sub 909 – 2009 Rate Case (Testimony related to prudence of Cliffside Coal Plant)

Docket No. E-7, Sub 1146 – 2017 Duke Energy Carolina Rate Case (Cost of Service Expert Witness)

Docket No. E-2, Sub 1142 – 2017 Duke Energy Progress Rate Case (Cost of Service Expert Witness)

Docket No. E-7, Sub 1214 – 2019 Duke Energy Carolina Rate Case (Cost of Service Expert Witness)

Docket No. E-2, Sub 1219 – 2019 Duke Energy Progress Rate Case (Cost of Service Expert Witness)

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Docket No. 2004-3-E– Approval of 2004 Duke Power Fuel Charge Adjustment - $938 million fuel expense

Docket No. 2005-3-E– Approval of 2005 Duke Power Fuel Charge Adjustment - $1,113 million fuel expense

Docket No. 2006-3-E – Approval of 2006 Duke Energy Carolinas Fuel Charge Adjustment - $1,318 million fuel expense

Docket No. 2007-440-E - Approval to Incur Project Development Costs for Lee Nuclear Station - $11 billion project

Docket No. 2011-20-E - Approval to Incur Project Development Costs for Lee Nuclear Station - $11 billion project

Docket No. 2013-392-E – Approval to Construct 750 MW Lee Combined Cycle Facility - $700 million project

Docket No. 2014-2-E - Approval of 2014 Duke Energy Carolinas Fuel Charge Adjustment - $1,318 million fuel expense

Docket No. 2018-318-E – 2018 Duke Energy Progress Rate Case (Cost of Service Expert Witness)

Docket No. 2018-319-E – 2019 Duke Energy Carolinas Rate Case (Cost of Service Expert Witness)

INDIANA UTILITIES REGULATORY COMMISSION

Cause No. 43114 IGCC-4S1 – Approval related to cost recovery of $3.3 billion 600 MW integrated gasification combined cycle plant

Cause No. 43114 IGCC-5 – Approval related to cost recovery of $3.3 billion 600 MW integrated gasification combined cycle plant

Cause No. 43596 – Duke Energy Indiana Purchase of Vermillion Generating Station and Retirement of Gallagher Units 1 & 3